Assessment of the Potential Costs and Energy Impacts of Spill Prevention, Control, and Countermeasure Requirements for U.S. Oil and Natural Gas Production

Report Prepared for the

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By

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Executive Summary

The purpose of this report is to summarize the results of an assessment of the energy supply and related economic impacts of federal Spill Prevention, Control, and Countermeasure (SPCC) requirements on U.S. oil and natural gas exploration and production (E&P) operations. Considerable uncertainty currently characterizes what the domestic oil and gas E&P industry may be required to do to comply, and many have expressed concern about the potential impact of these requirements on marginal oil and natural gas producers.

The federal SPCC rule was first promulgated in 1973 and became effective on January 10, 1974.[1] After three attempts to revise the rule in the 1990s, the Environmental Protection Agency (EPA) issued a final rule amending the SPCC regulations in July 2002.

In the 2002 SPCC rule, several relatively minor language changes dramatically altered, from the perspective of industry, the scope of the SPCC requirements. These include:

- The inclusion of the word "use" in Section 112.1(b)
- The change applicability from "tanks" to "containers" that "use" or store oil and have a maximum capacity of 55 gallons or more
- The change in the term "loading rack" to cover "loading and unloading areas"
- The inclusion of produced water storage tanks as vessels containing oil.

From industry's perspective, these will bring a number of other types of facilities and/or pieces of equipment at oil and natural gas E&P facilities under the jurisdiction of the rule, beyond the oil storage "tanks" originally perceived by industry to be the primary focus.

The energy supply and related economic impacts associated with these changes, assuming prices consistent to conditions in 2002, where wellhead crude oil prices averaged $22.51 per barrel (nominal), and wellhead natural gas prices average $2.95 per Mcf, and assuming a reference case set of compliance assumptions, are summarized as follows:

- The U.S. industry would spend nearly $3.2 billion complying with the new requirements.
- Shut in crude oil production would amount to over 326,000 barrels per day, amounting to 9% of U.S. oil production. Shut in natural gas production would amount to nearly 125 Bcf annually, amounting to about 1% of U.S. natural gas production.
- Public and private royalty holders would lose nearly $300 million in revenues from the lost production. State governments would lose over $139 million in lost revenues from severance taxes, and $170 million in state income taxes, while the federal government would lose over $1.3 billion in federal income tax receipts.

Under 2005 conditions, where prices were much higher, with wellhead crude oil prices averaging $50.26 per barrel (nominal), and wellhead natural gas prices averaging $7.51 per Mcf, the following impacts result:

- The U.S. industry would spend nearly $4.6 billion complying with the new requirements.

[1] *(38FR 34164)*

- Shut in crude oil production would amount to nearly 55,000 barrels per day, or 2% of U.S. oil production. Shut in natural gas production would amount to nearly 43 Bcf annually, less than 1% of U.S. natural gas production.
- Public and private royalty holders would lose on the order of $140 million in revenues from the lost production. State governments would lose over $67 million in lost revenues from severance taxes, and $207 million in lost income taxes, while the federal government would lose over $1.6 billion in federal income tax receipts.

An important consideration associated with these results is that at lower prices, more production would be shut in, and the impacts associated with this lost production, such as royalty and tax receipts, would be larger. On the other hand, at higher prices, the costs of compliance are larger, as are the impacts associated with the lost income resulting from these increased costs. Therefore, the impacts on state and federal income taxes collected from oil and gas production would be greater at higher prices.

One option that has been proposed to reduce the burden associated with the new SPCC requirement would be to waive the requirements with regard to vessels associated with produced water management facilities. However, this reduction would have only a minor effect in reducing the overall energy and economic impacts associated with the SPCC rule.

Another option that has been proposed to reduce the burden associated with the new SPCC requirement would be to waive the requirements with regard to flow and gathering lines, and process and facility piping. With this exemption:

- The U.S. industry would spend nearly $0.7 to $1.4 billion less to comply with the new requirements.
- Shut in crude oil production would be reduced by as much as 94,000 barrels per day, and shut in natural gas production would be reduced by as much as 20 Bcf per year.
- Public and private royalty holders would lose on the order of $20 to $80 million less in revenues from the lost production. State governments would lose $7 to $37 million less in lost revenues from severance taxes, and would lose from $45 to $58 billion less in income taxes. The federal government would lose $354 to $470 million less in federal income tax receipts.

Finally, some have proposed that "marginal wells" be exempt from new SPCC compliance requirements.[2] If these wells were, the energy and economic impacts would be dramatically reduced. Specifically, under the reference case compliance conditions and 2002 prices:

- Industry compliance costs would be reduced to $1.4 billion, compared to $3.2 to $4.5 billion if facilities associated with marginal wells were not exempt.
- No current crude oil production or natural gas production would be shut in, and no losses in royalties and state severance and ad valorem taxes would result.

[2] Marginal wells are typically defined as wells that produce less that 15 barrels of oil per day, or less that 90,000 cubic feet per day.

- State governments would lose about $50 million from state income taxes, rather than $170 to $207 million if marginal wells were not exempt (including consideration of only state income taxes). The federal government would lose on the order of $450 million, compared to $1.3 to $1.6 billion that would be lost if marginal wells were not exempt.

Summary results for all the scenarios considered in this assessment are presented in Table ES-1.

Table ES-1
Summary of Estimated Energy Impacts From Alternative SPCC Compliance Scenarios

	Lost Production				Compliance Costs (Million $)		Lost Royalties (Million $)		Lost State Sev. Taxes (Million $)		Lost State Inc Taxes (Million $)		Lost Fed Inc. Taxes (Million $)	
	Oil (Barrels per Day)		Natural Gas (MMcf/yr)											
Compliance Scenario	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**
Reference Case	326,176	55,133	124,823	43,260	$3,158	$4,635	$300	$140	$139	$67	$170	$207	$1,318	$1,617
No Produced Water Facilities	326,166	48,654	124,823	43,260	$3,034	$4,482	$300	$128	$139	$66	$164	$197	$1,271	$1,544
No Gathering Lines/Piping	232,082	45,177	105,069	40,776	$2,440	$3,230	$220	$119	$102	$60	$125	$149	$965	$1,147
No PW Facilities or Gathering/Piping	230,627	45,177	77,325	37,235	$2,305	$3,038	$208	$116	$96	$58	$117	$139	$908	$1,074
No Marginal Wells	0	n.e.	0	n.e.	$1,434	n.e.	$0	n.e.	$0	n.e.	$53	n.e.	$449	n.e.

Differences from Reference Case

	Lost Production				Compliance Costs (Million $)		Lost Royalties (Million $)		Lost State Sev. Taxes (Million $)		Lost State Inc Taxes (Million $)		Lost Fed Inc. Taxes (Million $)	
	Oil (Barrels per Day)		Natural Gas (MMcf/yr)											
Compliance Scenario	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**	**2002**	**2005**
Reference Case	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
No Produced Water Facilities	10	6,479	0	0	$124	$154	$0	$12	$0	$1	$6	$9	$47	$73
No Gathering Lines/Piping	94,094	9,955	19,754	2,484	$718	$1,405	$80	$20	$37	$7	$45	$58	$354	$470
No PW Facilities or Gathering/Piping	95,549	9,955	47,498	6,025	$853	$1,597	$92	$24	$43	$9	$53	$67	$410	$543
No Marginal Wells	326,176	n.e.	124,823	n.e.	$1,724	n.e.	$300	n.e.	$139	n.e.	$116	n.e.	$870	n.e.

These estimates of "what's at stake" show that SPCC requirements could very likely represent a "significant regulatory action" as defined by Executive Order 12866 or a "significant energy action" as defined by Executive Order 13211. The greatest mechanism available to reduce the energy and impacts associated with SPCC requirements on oil and gas exploration and production facilities would be to exempt facilities associated with marginally producing oil and gas wells. In addition, waiving requirements associated with flow and gathering lines, and process and facility piping would also help to reduce overall energy and economic impacts.

Background

The federal Spill Prevention, Control, and Countermeasure (SPCC) rule was first promulgated in 1973 and became effective on January 10, 1974.[3] After three attempts to revise the SPCC rule in the 1990s, the Environmental Protection Agency (EPA) issued a final rule amending the SPCC regulations in July 2002. The 2002 SPCC rule established requirements for non-transportation–related facilities with total above-ground oil storage capacity (in tanks or other oil-filled containers) greater than 1,320 gallons or with buried oil storage tank capacity greater than 42,000 gallons. The 2002 SPCC rule revisions became effective August 16, 2002, but EPA subsequently amended the rule in 2002, 2003, and 2004 to extend the compliance deadline. On December 12, 2005, EPA proposed further amendments to the 2002 rule, and then on February 10, 2006, extended the compliance date to October 31, 2007 for facilities to revise and implement their SPCC plans. The reason for the current extension is to provide EPA adequate time to take final action on the proposed 2005 amendments to the 2002 rule.[4]

In the 2002 SPCC rule, several relatively minor language changes dramatically altered, from the perspective of industry, the scope of the SPCC requirements. These include:

- The inclusion of the word “use” in Section 112.1(b)
- The change applicability from “tanks” to “containers” that “use” or store oil and have a maximum capacity of 55 gallons or more
- The change in the term “loading rack” to cover “loading and unloading areas”
- The inclusion of produced water storage tanks as vessels containing oil.

These changes will bring a number of other types of facilities and/or pieces of equipment at oil and natural gas exploration and production (E&P) facilities under the jurisdiction of the rule, beyond the storage “tanks” originally perceived by industry to be the primary focus.[5] New types of facilities/equipment falling under the rule’s jurisdiction include:

- Produced water treatment facilities and associated tanks which contain relatively small volumes of oil
- Process vessels such as separators, heater treaters, compressors, pump jacks, etc.
- Flow and gathering lines/ process and facility piping
- Emergency and temporary containers used in drilling and production operations, such as blowdown tanks, emergency tanks and pits, frac tanks, etc.

[3] *(38FR 34164)*
[4] http://www.epa.gov/oilspill/index.htm
[5] EPA asserts that the 1974 rule was always meant to apply to oil-filled equipment, and that the use of the terms “container” and “use” in the language of the 2002 rule is a clarification of the original intent of the 1974 rule. This is evident from “Appendix C, Summary of Revised SPCC Rule Provisions” in EPA’s *SPCC Guidance for Regional Inspectors* published November 28, 2005. In the discussion of minimum container size in the 2002 rule (section 112.1 (d) (5) EPA states that in the 1974 rule “…all containers, regardless of size, were considered to be subject to SPCC provisions.” Again, in the discussion of oil-filled equipment in the 2002 rule (section 112.2) EPA states that the language in the 2002 rule is a “clarification on the application of the rule to this type of equipment.”

- Truck loading areas at oil and gas production facilities.

While not the subject of this analysis, a number of other oil and gas related facilities and/or operations are also subject to the new requirements that would result from the language revisions in the 2002 SPCC Rule. These include:

- Petroleum bulk stations and terminals
- Gasoline service stations/vehicle rental facilities
- Fuel oil dealers
- Petroleum refining and related facilities
- Pipelines
- Other potential mobile oil filled equipment (e.g., bulldozers, service company trucks such as those used for hydraulic fracturing, seismic trucks, and rail cars that never leave the facility).

In addition, the revisions in the 2002 rule will impose incremental compliance costs associated with drilling, workover, and service rigs. While these increased requirements may lead to increases in the costs associated with providing these services that use this equipment, those increased costs and their associated impacts were not considered in this assessment.

Overview of Analytical Considerations

The analysis for this report focuses on the potential implications of SPCC compliance on domestic oil and gas production operations, with particular emphasis on that production that is currently economically marginal, and would be most impacted by increased compliance requirements. In addition, the analysis focuses primarily on the implications associated with the changes imposed by the 2002 rule.

For purposes of economic/energy impact modeling, several fundamental considerations need to explicitly be addressed:

- What types of “facilities” (equipment, processes, sites, etc.) must comply?
- How many/what portion of the “facilities” might be subject to new requirements?
- What types of requirements would apply to each type of “facility”?
- What will operators have/choose to do to comply?
- What will be the incremental costs associated with compliance? What will be the impact of compliance on project timing?
- How much will the domestic oil and gas industry have to spend to comply with the new requirements?
    - Initial compliance costs

- Recurring or ongoing costs (*for purposes of this analysis, the focus is primarily on initial compliance costs*).

- What will be the impact of these requirements on U.S. oil and gas production?
- What other economic impacts will result due to any oil and gas production shut in because of these new requirements?

Where uncertainties exist for any of the above factors, the impacts can be represented in terms of ranges or scenarios. Factors used in characterizing alternative scenarios could correspond to:

- Different interpretations of key requirements, either in law or by field inspectors
- Alternative approaches for exempting certain equipment and facilities from all or certain requirements. This could include produced water treatment facilities and associated tanks which contain relatively small volumes of oil, flow and gathering lines and/or process and facility piping, and/or tanks below a certain size.
- Alternative approaches that exempted facilities associated with marginal wells.[6]

For purposes of this assessment, one "reference case" was assessed, assuming applicability to all facilities, and several alterative scenarios were considered where certain types of facilities were assumed to be exempt.

General Logic for Determining New Facilities Subject to 2002 Rule

As described above, the 2002 changes to the SPCC rule result in a number of additional types of facilities and/or pieces of equipment being included under the jurisdiction of the rule, beyond the storage "tanks" originally perceived. However, not all facilities/equipment will need to take action to comply. For example:

- Some do not meet the size threshold.
  - For facilities that have a total storage capacity of less than 10,000 gallons, the operator is allowed to "self certify" their SPCC plan. *In this analysis, we are assuming that a negligible portion of oil and gas facilities would have a total storage capacity less than 10,000 gallons (238 barrels). Moreover, there is negligible benefit to operators as the only thing that is waived by the December. 12, 2005 proposal is the PE certification. The operator is still required to meet all other requirements and is not allowed to deviate from those requirements. Consequently, this provision of the December 12, 2005 proposed rulemaking would have minimal effect on oil and gas operations.*
  - No individual tank or piece of equipment stores more than 1,320 gallons.
- Some already are in compliance.

[6] Marginal wells are typically defined as wells that produce less that 15 barrels of oil per day, or less that 90,000 cubic feet per day.

- Some are located such that they pose no threat to “navigable waters” (Given EPA’s current interpretation of “navigable waters”, few operators were assumed to be able to claim that they do not pose a threat to “navigable waters.”)[7]

For facilities/equipment not in compliance, several choices can be made:

- Some will build new secondary containment around those parts of their facilities not in compliance.
- For some, this will be “impractical,” and they will instead choose to implement an inspection and maintenance (I&M) program, develop a contingency plan, and provide a written commitment to have the resources and trained personnel necessary for mitigation should a spill occur.

For facilities/equipment not in compliance:

- Some may be incorporated under an existing (upgraded) SPCC plan.
- Most will not be able to be incorporated into an existing facility’s plan, and will require a new SPCC plan. (Given the significant changes to the 2002 rule proposed, it is assumed that most facilities will develop a new plan.)

Therefore, this analysis assumes that facilities/equipment will need to pursue one of five sets of actions to comply:

- Install secondary containment and incorporate into an existing, upgraded SPCC plan.
- Install secondary containment and develop a new SPCC plan.
- Where secondary containment is determined to be impractical, implement an I&M program, develop a contingency plan, and incorporate into an existing, upgraded SPCC plan.
- Where secondary containment is determined to be impractical, implement an I&M program, develop a contingency plan, and prepare a new SPCC plan.
- Do nothing, since the facility/equipment is already in compliance, falls below a size/volume threshold, or does not threaten navigable waters.

Facilities Subject to the 2002 Requirements

Number of Impacted E&P “Facilities” in the U.S

For purposes of this analysis, the number of E&P “facilities” in the U.S. was estimated as a function of the number of producing wells. For crude oil, the Independent Petroleum Association of America (IPAA) estimates that there are 509,797 producing oil wells in the U.S. An average of 3 oil wells per tank battery was assumed, which constitutes the traditional definition of an

[7] The June 19, 2006 Supreme Court decision in the joint cases of *Rapanos v. United States* and *Carabell v. U.S. Army Corps of Engineers* may change this interpretation, but it is premature at this time to consider this potential impact.

SPCC-regulated "facility." This amounts to 169,932 oil production facilities. (As a comparison, EPA estimates that there are 171,992 "SPCC-regulated facilities" in the "oil production" sector in the U.S.[8])

Each facility was assumed to have, on average, 3 tanks per tank battery (two oil tanks and one produced water tank). This amounted to 509,797 tanks at oil production facilities.

For natural gas, the IPAA estimates that there are 395,023 producing natural gas wells in the U.S. However, natural gas production facilities, under the 2002 rule, would only fall under the SPCC requirements if they produced oil or condensate. For this, the number of conventional and unconventional natural gas wells that produce no oil or condensate was assumed to be 141,195, estimated as follows:

Type of gas well	Total number of gas wells	Portion of gas wells that produce no condensate	Number of dry gas wells
Shale	51,221	33%	16,903
Coalbed methane	28,790	100%	28,790
Tight gas sands	250,000	33%	82,500
Conventional	65,012	20%	13,002
Total			**141,195**

Source: Advanced Resources International, Inc.

Thus, 253,828 gas wells are assumed to produce condensate (estimated by subtracting 141,195 from 395,023). Assuming 2 wells per facility, an estimated 126,914 gas facilities are in operation in the U.S. that produce at least some oil and/or condensate. (As comparison, EPA estimates that there are 41,083 "SPCC-regulated facilities" in the "gas production" sector in the U.S.[9]) Therefore, an estimated 380,742 tanks are assumed in the gas production sector that potentially are under the jurisdiction of the 2002 SPCC rule, assuming 3 tanks per natural gas facility producing oil and/or condensate.

In the discussion that follows, estimates are developed for the various types of equipment that will fall under jurisdiction of the 2002 rule.

Bringing Produced Water (PW) Facilities and Associated Tanks into Compliance

According to the EPA Underground Injection Control (UIC) Program, there are approximately 167,000 Class II salt-water disposal (SWD) wells in the U.S.[10] Class II UIC wells are distinct from oil and gas production wells, and are those wells used to inject water or other fluids (such as CO_2) in association with oil and gas production operations. For purposes of this exercise, 80%

[8] U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, Office of Emergency Management, *Regulatory Analysis for the Proposed Revisions to the Oil Pollution Prevention Regulation (40 CFR Part 112)*, November 2005.
[9] U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, Office of Emergency Management, *Regulatory Analysis for the Proposed Revisions to the Oil Pollution Prevention Regulation (40 CFR Part 112)*, November 2005.
[10] http://www.epa.gov/safewater/uic/classii.html

were assumed to be associated with oil production operations and 20% with natural gas production facilities.[11] In addition, produced water storage tanks were assumed to be associated with each Class II well. Moreover, all of the produced water storage tanks were assumed to exceed the 1,320 size threshold and could threaten navigable waters, and none were assumed to be in facilities that fell below the 10,000 gallon total facility storage capacity limit.

Based on the operator surveys conducted by IPAA, the Domestic Petroleum Council (DPC), and the Oklahoma Independent Petroleum Association (OIPA), 66% of existing produced water tanks were assumed to be already contained within existing SPCC plans and have secondary containment. Of those that now must comply, 60% of oil facilities and 30% of natural gas facilities were assumed to install secondary containment, and thus, 40% of oil facilities and 70% of gas facilities were assumed to implement I&M programs and contingency plans.

In addition, of those produced water facilities not now in compliance, 20% were assumed to be incorporated into existing, upgraded SPCC plans, while 80% must be part of a new SPCC plan.

<u>Bringing Process Vessels (Heater Treaters and Separators) into Compliance</u>

For purposes of this exercise, all facilities were assumed to have some type of separation equipment. For example, at least one process vessel was assumed to be at each oil production gas production facility. This would amount to:

169,932 process vessels at oil production facilities
<u>126,914 process vessels at gas production facilities producing oil/condensate</u>

296,846 total number of process vessels

(This compares to estimates by the EPA Natural Gas Star Program that there are approximately 181,670 process vessels associated with oil and gas operations in the U.S., which include heater treaters, light oil separators, and heavy oil separators.[12])

All of these vessels were assumed to be in facilities that exceed the 10,000 gallon threshold and/or could threaten "navigable waters".

Based on the operator surveys, 25% of existing process vessels were assumed to be already contained within existing SPCC plans and have secondary containment. Of those that now must comply, 75% of oil and gas facilities were assumed to install secondary containment, and thus 25% of oil and gas facilities were assumed to implement I&M programs and contingency plans. Of those that now must comply, it was assumed that 20% can be incorporated into existing, upgraded SPCC plans, and 80% must be part of a new SPCC plan.

<u>Bringing Compressors into Compliance</u>

According to the EPA Natural Gas Star Program, there are 2,467 compressors at oil facilities, and 22,453 compressors at gas facilities in the U.S.[7] A negligible number were assumed to be located in facilities that fell below the 10,000 gallon total facility storage capacity limit.

[11] Including natural gas facilities producing coalbed methane.
[12] EPA Greenhouse Gas Inventory (http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html).

Based on the operator surveys, 10% of existing compressors were assumed to be already contained within existing SPCC plans and have secondary containment. Of those that now must comply, 10%[13] of oil and gas facilities were assumed to install secondary containment around compressors, and thus 90% of oil and gas facilities were assumed to implement I&M programs and contingency plans with regard to compressors.

Of those that now must comply, it was assumed that 20% can be incorporated into existing, upgraded SPCC plans, and that 80% must be part of a new SPCC plan

Bringing Blowdown and/or Emergency Tanks into Compliance

According to the EPA Natural Gas Star Program, there are 181,670 blowdown tanks at oil facilities, and 180,504 blowdown/emergency tanks at gas facilities in the U.S. [14] These are emergency tanks that could, at some time, be used to provide emergency storage for oil and/or for water that potentially could contain oil. It was assumed that none were located in facilities that fell below the 10,000 gallon total facility storage capacity limit.

Based on the operator surveys, 75% of existing tanks at oil facilities and 33% at gas facilities were assumed to be already contained within existing SPCC plans and have secondary containment. Of those that now must comply because they are not within secondary containment, 25% of oil and gas facilities were assumed to install secondary containment around these tanks, and 75% of oil and gas facilities were assumed to implement I&M programs and contingency plans with regard to these tanks. Of those that now must comply, it was assumed that 20% can be incorporated into existing, upgraded SPCC plans, and 80% must be part of a new SPCC plan.

Bringing Flow and Gathering Lines into Compliance

According to the EPA Natural Gas Star Program, there are 16,214 miles of gathering lines at oil facilities, and 298,035 miles of gathering lines at gas facilities in the U.S. [14] This amounts to:

- 670 feet of gathering lines per oil facility
- 12,150 of gathering lines per gas facility (of which 63% is assumed to be at wet gas facilities, based on the discussion above).

It was assumed that none of these flowlines/gathering lines were located in facilities that fell below the 10,000 gallon total facility storage capacity limit.

Based on the operator surveys, 10% of these flowlines/gathering systems were assumed to be already contained within existing SPCC plans. Of those that now must comply, 10% of oil and gas facilities were assumed to install secondary containment, and thus 90% were assumed to implement I&M programs and contingency plans with regard to these systems

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[13] These proportions were estimated to be reduced by more than half (from 25% to 10%) as a result of the provision in the December 12, 2005 proposed rule allowing owners/operators of oil-field operational equipment the alterative to secondary containment without making an individual impracticality determination.

[14] EPA Greenhouse Gas Inventory (http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html).

Of those that now must comply, it was assumed that 20% can be incorporated into existing, upgraded SPCC plans, and 80% must be part of a new SPCC plan.

Bringing Truck Loading Areas into Compliance

According to the EPA Natural Gas Star Program, there are 726 centralized gas processing facilities in the U.S.[15] In addition; it was assumed that there are 169,932 oil production facilities and 126,914 gas production facilities that produce oil and/or condensate in the U.S. (see above). Truck loading areas were assumed to be at each of these facilities. None of these loading areas were assumed to be located in facilities that fell below the 10,000 gallon total facility storage capacity limit.

Based on the operator surveys, 30% of the loading areas at oil and gas production facilities and 10% of the loading areas at gas processing facilities were assumed to be already contained within existing SPCC plans. Of those that now must comply, 10% of production and gas processing facilities were assumed to install secondary containment around their loading areas, and 90% were assumed to implement I&M programs and contingency plans with regard to these systems.

Of those that now must comply, it was assumed that 20% can be incorporated into existing, upgraded SPCC plans, and 80% must be part of a new SPCC plan.

Bringing Pump Jacks into Compliance

Pump jacks were assumed to be associated with each of the 509,797 oil wells in the U.S., with 10% of the pump jacks assumed to have capacities exceeding the 55 gallon threshold. Based on the operator surveys, no pump jacks were assumed to be already covered within existing SPCC plans. Of those that now must comply, 70% were assumed to install secondary containment around pump jacks, and 30% were assumed to implement I&M programs and contingency plans.

Of those that now must comply, it was assumed that 20% can be incorporated into existing, upgraded SPCC plans, and 80% must be part of a new SPCC plan.

Estimating the Incremental Compliance Costs

As described above, this analysis assumes that facilities/equipment will require one of five sets of actions to comply with the 2002 rule:

- Install secondary containment and incorporate into an existing, upgraded SPCC plan
- Install secondary containment and develop a new SPCC plan
- Where secondary containment is determined to be impractical, implement an I&M program and develop a contingency plan, and incorporate into an existing, upgraded SPCC plan

[15] EPA Greenhouse Gas Inventory (http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html).

*(Note: We determined that the **cost** difference associated with seeking approval for an impracticality determination was negligible, though this provision offered in the December 12, 2005 proposed rule would likely have an impact on project timing, where applicable.)*

- Where secondary containment is determined to be impractical, implement an I&M program and develop a contingency plan, and prepare a new SPCC plan
- Nothing, the facility/equipment is already in compliance, falls below the size threshold, or does not threaten navigable waters.

Upgrading Current and Developing New SPCC Plans

Even for facilities currently covered by an existing SPCC plan, the 2002 rule sets forth substantial changes that will need to be made to existing plans, *even if no new equipment or facilities are added, or other additional compliance must be pursued.* Requirements for upgrading existing SPCC plans include:

- Reviewing current plans and processes
- Providing substantially more detailed and comprehensive drawings and information on each facility
- Adapting existing SPCC plans to make them consistent with the dramatically reorganized structure of the 2002 rule
- Recertifying plans by a Professional Engineer (PE).

For costing purposes, it was assumed that each facility with an existing SPCC plan would, at a minimum, have to:

- Upgrade their existing SPCC plans, at an assumed cost of $1,000 per plan
- Receive PE certification for their upgraded plan, at a cost of $500 per plan.

If a piece of equipment or operation that previously was not part of a SPCC plan must now be incorporated into an existing SPCC Plan, then the costs associated with that equipment or operation are assumed to be half of the estimates provided above.

For any piece of equipment requiring a new SPCC plan (i.e., it cannot be incorporated into an existing SPCC Plan), the costs assumed for developing a new SPCC plan and obtaining a PE certification is $3,500 per plan.

These cost estimates are consistent with estimates provided in the industry surveys, and are near the average of the costs from a wide variety of sources, including EPA.

Providing Secondary Containment or Other Appropriate Alternatives

The costs of secondary containment or the costs associated with approved alternatives if secondary containment is determined to be impractical were assumed to vary for different types of equipment or operations, as summarized in the table below:

	Storage Tanks	Vessels	Flow and Gathering Lines	Blowdown/ Emergency Tanks	Compressors	Loading Areas
Secondary Containment	**$3,000**	**$3,000**	**$10,000**	**$3,000**	**$3,000**	**$5,000**
or						
Impracticality Determinations	**$1,000**	**$1,000**	**$5,500**	**$1,000**	**$1,000**	**$2,500**
Implement inspection and testing program	$500	$500	$5,000	$500	$500	$2,000
Develop and implement oil spill contingency plan	$500	$500	$500	$500	$500	$500
Written commitment to control/remove discharge	$0	$0	$0	$0	$0	$0

These cost estimates are consistent with estimates provided in various sources, including industry surveys and EPA regulatory impact studies.

Allocating Incremental SPCC Compliance Costs to Existing Production Wells

Estimates of the total costs of compliance for the oil and gas exploration and production industry were estimated by multiplying the number of pieces of equipment or types of operation corresponding to each compliance option, multiplied by the unit cost of compliance for that option. These were then aggregated to determine the total costs for all oil and natural gas facilities falling under the jurisdiction of the SPCC rule. The total incremental compliance costs associated with oil production facilities were divided by the number of producing oil wells in the U.S. to estimate the incremental compliance costs per oil well. Likewise, the total incremental compliance costs associated with natural gas production facilities were divided by number of producing gas wells in the U.S. to estimate the incremental compliance costs per gas well.

For the reference case set of conditions described above, estimated incremental compliance costs are $9,018 per producing oil well and $9,566 per producing gas well.

Estimating the Impact of Incremental SPCC Compliance Costs on Oil and Gas Production

The analytical approach used for assessing the impact of increased costs to comply with the SPCC rule, primarily as promulgated in the 2002 rulemaking, consisted of a number of steps, as described in the following.

Step1. Establish data base of U.S. oil and gas production

The Energy Information Administration (EIA) publishes a table showing U.S. oil and gas wells sorted by production rate categories.[16] A similar table is available for each state. For each rate category, the table provides the number of wells in the U.S. in that rate category, the production associated with those wells, and the average production rate per well (for both oil and gas). The latest year for which EIA has published this data is 2002.

[16] http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html

Step 2: Estimate average annual revenues per well for each rate category

Using EIA data for average annual wellhead oil and gas prices, average operating revenues per well were estimated for each rate category. One set of analysis assumed conditions in 2002 (consistent with the year of the EIA production data). The second set assumed more recent price conditions based on 2005 annual average wellhead prices.

These assumed average wellhead prices are summarized in the following table:

ASSUMED AVG. WELLHEAD PRICES	2002	2005
Crude Oil ($/Bbl)	$22.51	$50.26
Natural Gas ($/Mcf)	$2.95	$7.51

Estimates of average revenues per well for both the 2002 and 2005 price cases assumed to apply to the EIA breakdown of producing wells by category for 2002.

Step 3: Estimate production costs for each rate category

Using data from EIA's annual survey of oil and gas lease equipment and operating costs,[17] typical or representative annual operation and maintenance (O&M) costs per well were calculated. Again, O&M costs were calculated for both 2002 and 2005 conditions.[18]

Step 4: Estimate average annual operation income per well

For both the 2002 and 2005 cases, estimates of average operating income per well were developed for each rate category, by subtracting the average annual O&M costs per well from the average estimated revenue per well. This income represents that corresponding to well economics prior to the imposition of any new SPCC requirements.

Step 5. Estimate average annual operation income per well, accounting for incremental SPCC requirements

Again for both the 2002 and 2005 conditions, revised estimates of average operating income per well were developed for each rate category by adding the incremental SPCC compliance costs to the average annual operating costs per well, and then subtracting the revised average annual O&M costs per well from the average estimated revenue per well. This income represents that corresponding to well economics after the imposition of the SPCC requirements.

Step 6. Determine shut in production as a result of the increased SPCC costs

The process of adding the incremental costs for SPCC compliance results in costs exceeding revenues for certain categories of low productivity or "marginal" wells. The amount of production for these rate categories was assumed to be shut-in, since wells in the category, on average, would no longer be profitable to produce.

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17 http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html

18 The 2005 conditions assumed 2004 O&M costs, the last year that cost data are available from EIA.

Step 7. Extrapolate results to all U.S. production

The EIA table of U.S. oil and gas wells sorted by production rate category does not account for all producing oil and gas wells in the U.S. Specifically, they do not include gas wells from IL, IN and KY, oil wells from NY, and oil and gas wells from MD, OH, PA, TN, VA and WV. Impacts on production in the states analyzed were extrapolated to the U.S. total based on the assumptions that the total amount of shut-in production, proportionally, in excluded states was the same as that for the states included in the assessment. (This may be an understatement, since much of the production in the states not included generally consists of low-rate or marginal production wells.)

Step 8. Estimate other associated economic impacts

Estimated associated economic impacts were estimated based as a results of the increased costs all wells would incur to comply with the new requirements, as well as those resulting from the production that would be shut in since the oil and/or gas production from these wells would not generate enough revenue to cover the incremental costs of compliance with the SPCC requirements. The methods for estimating these economic impacts are described in the following:

- Estimated Compliance Expenditures. Estimated incremental compliance expenditures associated with onshore producing oil and gas wells were estimated by multiplying the estimated weighted average compliance costs by the number of wells complying. Wells that were assumed to be shut in were not assumed to incur the incremental compliance costs.
- Estimated Lost Royalties. Estimated lost royalties were determined by assuming royalties at 1/8 of wellhead revenues, equivalent to current rates in most onshore areas of the country. This includes both royalties paid to private royalty interest owners and royalties paid to the federal government, with no distinction made between the two.
- Estimated Lost State and Local Severance/Ad Valorum Taxes. Estimated state and local severance taxes were estimated based on individual severance and ad valorem tax rates for the states assessed.[19] These rates were applied to estimated wellhead revenues. These were estimated based on revenues to operating and working interest owners, as well as revenues from royalties.
- Estimated Lost State Income Taxes. Lost state income taxes were estimated both on the lost production due to some wells being shut in because of the incremental compliance requirements, as well as a result of the decrease in income from wells remaining on production but incurring increased costs. Estimated state and local severance taxes were estimated based on individual state corporate tax rates.[20]
- Estimated Lost Federal Income Taxes. Lost federal income taxes were also estimated both on the lost production due to some wells being shut in because of the incremental

[19] Estimates of state severance and ad valorem tax rates were based on that reported in Interstate Oil and Gas Compact Commission, *Summary of Severance, Ad Valorem and Total Oil and Gas Tax Rates of IOGCC Member States*, October 2002.
[20] http://www.taxadmin.org/fta/rate/corp_inc.html

compliance requirements, as well as a result of the decrease in income from wells remaining on production but incurring increased costs. A corporate federal tax rate of 35% was assumed for these estimates.

Summary of Results

The energy supply and related economic impacts associated with the 2002 SPCC rule changes were estimated assuming prices consistent to conditions in 2002, where wellhead crude oil prices averaged $22.51 per barrel (nominal), and wellhead natural gas prices average $2.95 per Mcf. Under the reference case set of assumptions, where estimated incremental compliance costs are $9,018 per producing oil well and $9,566 per producing gas well, the results are summarized as follows:

- The U.S. industry would spend nearly $3.2 billion complying with the new requirements.
- Shut in crude oil production would amount to over 326,000 barrels per day), amounting to 9% of U.S. oil production.
- Shut in natural gas production would amount to nearly 125 Bcf annually, amounting to about 1% of U.S. natural gas production.
- Public and private royalty holders would lose on the order of $300 million in revenues from the lost production.
- State governments would lose over $139 million in lost revenues from state and local severance and ad valorem taxes, and $170 million in lost state income taxes.
- The federal government would lose over $1.3 billion in federal income tax receipts.

Under 2005 conditions, where prices were much higher, with wellhead crude oil prices averaging $50.26 per barrel (nominal), and wellhead natural gas prices averaging $7.51 per Mcf, the following impacts result:

- The U.S. industry would spend nearly $4.6 billion complying with the new requirements.
- Shut in crude oil production would amount to nearly 55,000 barrels per day, amounting to 2% of U.S. oil production.
- Shut in natural gas production would amount to nearly 43 Bcf annually, amounting to less than 1% of U.S. natural gas production.
- Public and private royalty holders would lose on the order of $140 million in revenues from the lost production.
- State governments would lose over $67 million in lost revenues from state and local severance and ad valorem taxes, and $207 million in lost state income taxes.
- The federal government would lose over $1.6 billion in federal income tax receipts.

These results are presented in detail by state in Table 1.

Table 1
SUMMARY OF IMPACTS OF INCREASED COSTS OF SPCC COMPLIANCE ON U.S. MARGINAL OIL AND GAS PRODUCTION

	Shut In Oil Prod.		Shut In Gas Prod.		Lost Royalties		Lost Sev. Taxes		Compliance Costs		Lost St. Inc. Taxes		Lost Fed. Inc. Taxes	
	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005
STATE	(MBOE)	(MBOE)	(MMcfe)	(MMcfe)	(M $/yr)	(M $/yr)	(M $/yr)	(M $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)
Alabama	131	10	542	103	$569	$159	$455	$127	$32	$40	$3	$3	$13	$13
Arkansas	618	133	698	165	$1,996	$990	$719	$356	$36	$47	$2	$2	$13	$15
Arizona	5	1	4	2	$16	$8	$21	$11	$0	$0	$0	$0	$0	$0
California	8,056	2,331	710	236	$22,930	$14,869	$1,834	$1,190	$313	$366	$34	$36	$100	$107
Colorado	1,368	135	6,372	1,279	$6,200	$2,046	$3,720	$1,228	$150	$210	$9	$10	$62	$66
Florida	3	0	1	1	$8	$0	$5	$0	$1	$1	$0	$0	$0	$0
Illinois	2,079	191	0	0	$5,851	$1,199	$0	$0	$14	$39	$2	$3	$14	$14
Indiana	419	41	0	0	$1,178	$256	$94	$20	$3	$8	$1	$1	$2	$3
Kansas	12,888	1,750	3,419	848	$37,525	$11,792	$24,016	$7,547	$172	$333	$12	$15	$89	$118
Kentucky	357	58	0	0	$1,006	$363	$563	$203	$2	$6	$0	$0	$1	$2
Louisiana	2,780	1,745	7,389	5,580	$10,548	$16,200	$10,548	$16,200	$107	$120	$11	$16	$36	$52
Michigan	1,151	222	522	144	$3,431	$1,530	$1,647	$735	$75	$96	$2	$2	$29	$33
Mississippi	36	12	91	15	$134	$87	$64	$42	$23	$23	$1	$1	$7	$7
Montana	1,125	159	2,872	725	$4,223	$1,678	$3,041	$1,208	$29	$61	$4	$5	$17	$19
Nebraska	441	13	56	14	$1,263	$92	$303	$22	$6	$11	$1	$1	$2	$3
Nevada	8	0	0	0	$22	$1	$2	$0	$1	$1	$0	$0	$0	$0
New York	0	0	6,680	3,316	$2,463	$3,113	$0	$0	$6	$17	$1	$3	$14	$14
New Mexico	3,630	421	7,719	1,888	$13,059	$4,417	$8,880	$3,004	$287	$374	$26	$30	$94	$107
North Dakota	378	21	82	20	$1,094	$150	$788	$108	$27	$31	$2	$2	$8	$9
Oklahoma	14,163	2,259	10,925	2,512	$43,880	$16,550	$24,573	$9,268	$344	$561	$31	$37	$148	$181
Oregon	0	0	6	0	$2	$0	$1	$0	$0	$0	$0	$0	$0	$0
South Dakota	2	0	51	8	$24	$10	$9	$4	$1	$2	$0	$0	$1	$1
Texas	31,947	4,832	29,740	7,797	$100,859	$37,680	$37,116	$13,866	$1,089	$1,564	$0	$0	$456	$593
Utah	198	14	439	84	$719	$169	$173	$41	$42	$47	$2	$2	$14	$14
West Virginia	613	302	43,370	15,383	$17,718	$16,339	$7,087	$6,535	$44	$201	$17	$26	$50	$76
Wyoming	2,320	297	3,134	930	$7,683	$2,740	$6,146	$2,192	$194	$239	$0	$0	$80	$87
Total for States	**84,717**	**14,946**	**124,823**	**41,050**	**$284,401**	**$132,437**	**$131,807**	**$63,907**	**$2,997**	**$4,398**	**$161**	**$196**	**$1,251**	**$1,534**
Total Onshore (extrapolated)	**119,054**	**20,123**	**124,823**	**43,260**	**$299,713**	**$139,568**	**$138,903**	**$67,348**	**$3,158**	**$4,635**	**$170**	**$207**	**$1,318**	**$1,617**
Total Onshore Daily Production Rate (Bbl/day, or MMcf/day)	**326,176**	**55,133**	**341,980**	**118,522**										

An important consideration associated with these results is that at lower prices, more production would be shut in, and the impacts associated with this lost production, such as royalty and tax receipts, would be larger. On the other hand, at higher prices, the costs of compliance are larger, as are the impacts associated with the lost income resulting from these increased costs. Therefore, the impacts on state and federal income taxes collected from oil and gas production would be greater at higher prices.

Alternative Regulatory Compliance Scenarios

Produced Water

One option to reduce the burden associated with the new SPCC requirement would be to waive the requirements with regard to vessels associated with produced water management facilities. Produced water contains only small amounts of oil, and would pose a minimal threat even if a spill occurs. If produced water vessels are exempt from the SPCC requirements, estimated incremental compliance costs would be reduced to $8,506 per producing oil well (a 6% reduction) and $9,309 per producing gas well (a 3% reduction). With this exemption:

- The U.S. industry would spend nearly $124 to $154 million less complying with the new requirements, depending prices.

- Shut in crude oil production and natural gas production would be only minimally impacted, as would the revenue streams to the royalties and severance taxes associated with any lost production.
- The federal government would lose from $47 to $73 million less in federal income taxes, and state governments would lose $6 to $10 million less.

All told, this reduction would have a minor effect in reducing the overall economic and energy impacts associated with the SPCC rule.

Flow and Gathering Lines and Process and Facility Piping

Another option to reduce the burden associated with the new SPCC rules would be to waive requirements for flow and gathering lines and process and facility piping, since providing secondary containment for these facilities is impractical. If these gathering and piping systems were exempt, estimated incremental compliance costs would be reduced to $6,043 per producing oil well (a 33% reduction) and $6,699 per producing gas well (a 30% reduction). With this exemption:

- The U.S. industry would spend nearly $0.7 to $1.4 billion less complying with the new requirements.
- Shut in crude oil production would be reduced by as much as 94,000 barrels per day.
- Shut in natural gas production would be reduced by as much as 20 Bcf per year.
- Public and private royalty holders would lose on the order of $20 to $80 million less in revenues from the lost production.
- State governments would lose $7 to $37 million less in lost revenues from severance taxes, and would lose from $45 to $58 billion less in income taxes.
- The federal government would lose $354 to $470 million less in federal income tax receipts.

Flow and Gathering Lines and Process and Facility Piping, Coupled with Produced Water

Another option to reduce the burden associated with the new SPCC requirement would involve waiving the requirements for both flow and gathering lines/process and facility piping and produced water management facilities. With this option, estimated incremental compliance costs would be reduced to $5,531 per producing oil well (a 39% reduction) and $6,442 per producing gas well (a 33% reduction). The impacts associated with this option are comparable to those associated with the case where only gathering systems and field piping are exempt, although some reductions in overall impacts result.

Tiered Approach

A tiered approach has been proposed by some in the oil and gas industry that accounts for needs of small volume storage facilities and tank farm operations *[clarify]*. This approach provides a suggested streamlined approach for those facilities that could reasonably impact navigable waters.

- Tier 1: Aggregate storage capacity of 50,000 gallons or less for each facility. This proposed threshold is 5% of the facility response plan (FRP) threshold (i.e. 1,000,000 gallons of oil storage where there is no transfer of oil over water). This tier includes:
    - No single tank at a facility would exceed a nominal capacity of 21,000 gallons or 500 barrels. The risk of all tanks failing at the same time would be minimal.
    - Eliminates the requirements for operations/process equipment, flow lines, loading/unloading areas, integrity testing, and other various requirements currently required for a facility that typically has a greater single storage capacity and higher throughput.
    - Requires a one page plan and/or a spreadsheet matrix
        - Includes operator/owner's name, address and contact information; well name and location; volume calculations showing facility storage capacity; size of storage tanks, and size of secondary containment needed for those tanks; emergency contact information; and signature of authorized representative of owner/operator.
        - No P.E. certification of plan
        - For new well completions or recently purchased wells, the operator would have 6 months after well testing is completed or purchase closing date to develop a SPCC plan and to implement secondary containment around the storage tanks.
- Tier 2: Aggregate storage capacity of 50,001 gallons to 999,999 gallons. This tier would include full requirements in accordance with existing 2002 SPCC rules.
- Tier 3: Aggregate storage capacity of 1,000,000 gallons or greater. This would require facilities to follow existing Facility Response Plan requirements.

However, since the proportion of oil and gas facilities included in these categorization based on aggregate storage capacity is currently unknown, the impact of this proposal could not be assessed.

Marginal Wells

Finally, several associations of oil and gas producers, as well as some state oil and gas regulatory agencies, have proposed that “marginal wells” be exempt from new SPCC compliance requirements. Marginal wells are typically defined as wells that produce less that 15 barrels of oil per day, or less that 90,000 cubic feet per day. If these wells were exempt from the SPCC requirements as set forth in the 2002 rule, the energy and economic impacts would be dramatically reduced. Specifically, under the reference case compliance conditions and 2002 prices:

- Under either price scenario, industry compliance costs would be reduced to $1.4 billion, compared to $3.2 to $4.6 billion if facilities associated with marginal wells were not exempt.
- No current crude oil production or natural gas production would be shut in, and no losses in royalties and state severance and ad valorem taxes would result.
- State governments would lose on the order of $50 million from state income taxes, rather than $170 to $207 million if marginal wells were not exempt (including consideration of only state income taxes).
- The federal government would lose on the order of $450 million, compared to $1.3 to $1.6 billion in that would be lost if marginal wells were not exempt.

These results for the case where marginal wells are exempt are presented in detail by state in Table 2.

Table 2

SUMMARY OF IMPACTS OF INCREASED COSTS OF SPCC COMPLIANCE ON U.S. MARGINAL OIL AND GAS PRODUCTION

	Shut In Oil Prod.		Shut In Gas Prod.		Lost Royalties		Lost Sev. Taxes		Compliance Costs		Lost St. Inc. Taxes		Lost Fed. Inc. Taxes	
	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005
STATE	(MBOE)	(MBOE)	(MMcfe)	(MMcfe)	(M $/yr)	(M $/yr)	(M $/yr)	(M $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)	(MM $/yr)
Alabama	0	0	0	0	$0	$0	$0	$0	$16	$16	$1	$1	$5	$5
Arkansas	0	0	0	0	$0	$0	$0	$0	$17	$17	$1	$1	$5	$5
Arizona	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
California	0	0	0	0	$0	$0	$0	$0	$156	$156	$14	$14	$41	$41
Colorado	0	0	0	0	$0	$0	$0	$0	$68	$68	$3	$3	$21	$21
Florida	0	0	0	0	$0	$0	$0	$0	$1	$1	$0	$0	$0	$0
Illinois	0	0	0	0	$0	$0	$0	$0	$3	$3	$0	$0	$1	$1
Indiana	0	0	0	0	$0	$0	$0	$0	$1	$1	$0	$0	$0	$0
Kansas	0	0	0	0	$0	$0	$0	$0	$62	$62	$2	$2	$19	$19
Kentucky	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Louisiana	0	0	0	0	$0	$0	$0	$0	$73	$73	$6	$6	$20	$20
Michigan	0	0	0	0	$0	$0	$0	$0	$19	$19	$0	$0	$6	$6
Mississippi	0	0	0	0	$0	$0	$0	$0	$13	$13	$1	$1	$4	$4
Montana	0	0	0	0	$0	$0	$0	$0	$15	$15	$1	$1	$4	$4
Nebraska	0	0	0	0	$0	$0	$0	$0	$1	$1	$0	$0	$0	$0
Nevada	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New York	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Mexico	0	0	0	0	$0	$0	$0	$0	$141	$141	$11	$11	$39	$39
North Dakota	0	0	0	0	$0	$0	$0	$0	$15	$15	$1	$1	$4	$4
Oklahoma	0	0	0	0	$0	$0	$0	$0	$129	$129	$8	$8	$37	$37
Oregon	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
South Dakota	0	0	0	0	$0	$0	$0	$0	$1	$1	$0	$0	$0	$0
Texas	0	0	0	0	$0	$0	$0	$0	$492	$492	$0	$0	$172	$172
Utah	0	0	0	0	$0	$0	$0	$0	$25	$25	$1	$1	$7	$7
West Virginia	0	0	0	0	$0	$0	$0	$0	$4	$4	$0	$0	$1	$1
Wyoming	0	0	0	0	$0	$0	$0	$0	$108	$108	$0	$0	$38	$38
Total for States	**0**	**0**	**0**	**0**	**$0**	**$0**	**$0**	**$0**	**$1,361**	**$1,361**	**$51**	**$51**	**$426**	**$426**
Total Onshore (extrapolated)	**0**	**0**	**0**	**0**	**$0**	**$0**	**$0**	**$0**	**$1,434**	**$1,434**	**$53**	**$53**	**$449**	**$449**
Total Onshore Daily Production Rate (Bbl/day, or MMcf/day)	**0%**	**0%**	**0%**	**0%**										
	0	0	0	0										

Summary results for all the scenarios considered are summarized in Table 3.

Table 3
Summary of Estimated Energy Impacts From Alternative SPCC Compliance Scenarios

	Lost Production				Compliance Costs (Million $)		Lost Royalties (Million $)		Lost State Sev. Taxes (Million $)		Lost State Inc Taxes (Million $)		Lost Fed Inc. Taxes (Million $)	
	Oil (Barrels per Day)		Natural Gas (MMcf/yr)											
Compliance Scenario	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005
Reference Case	326,176	55,133	124,823	43,260	$3,158	$4,635	$300	$140	$139	$67	$170	$207	$1,318	$1,617
No Produced Water Facilities	326,166	48,654	124,823	43,260	$3,034	$4,482	$300	$128	$139	$66	$164	$197	$1,271	$1,544
No Gathering Lines/Piping	232,082	45,177	105,069	40,776	$2,440	$3,230	$220	$119	$102	$60	$125	$149	$965	$1,147
No PW Facilities or Gathering/Piping	230,627	45,177	77,325	37,235	$2,305	$3,038	$208	$116	$96	$58	$117	$139	$908	$1,074
No Marginal Wells	0	n.e.	0	n.e.	$1,434	n.e.	$0	n.e.	$0	n.e.	$53	n.e.	$449	n.e.

Differences from Reference Case

	Lost Production				Compliance Costs (Million $)		Lost Royalties (Million $)		Lost State Sev. Taxes (Million $)		Lost State Inc Taxes (Million $)		Lost Fed Inc. Taxes (Million $)	
	Oil (Barrels per Day)		Natural Gas (MMcf/yr)											
Compliance Scenario	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005	2002	2005
Reference Case	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
No Produced Water Facilities	10	6,479	0	0	$124	$154	$0	$12	$0	$1	$6	$9	$47	$73
No Gathering Lines/Piping	94,094	9,955	19,754	2,484	$718	$1,405	$80	$20	$37	$7	$45	$58	$354	$470
No PW Facilities or Gathering/Piping	95,549	9,955	47,498	6,025	$853	$1,597	$92	$24	$43	$9	$53	$67	$410	$543
No Marginal Wells	326,176	n.e.	124,823	n.e.	$1,724	n.e.	$300	n.e.	$139	n.e.	$116	n.e.	$870	n.e.

Conclusion

Regardless of scenario considered, these results show that potential SPCC requirements could very likely represent a "significant regulatory action" as defined by Executive Order 12866 or a "significant energy action" as defined by Executive Order 13211. The greatest mechanism available to reduce the energy and impacts associated with SPCC requirements on oil and gas exploration and production facilities would be to exempt facilities associated with marginally producing oil and gas wells. In addition, waiving requirements associated with flow and gathering lines, and process and facility piping would also help to reduce overall energy and economic impacts.

APPENDIX A

BREAKDOWN OF INCREMENTAL COMPLIANCE COSTS FOR POTENTIAL NEW SPCC REQUIREMENTS BY TYPE OF E&P FACILITY/EQUIPMENT AND COMPLIANCE COST ELEMENT (Reference Case)

This appendix provides a breakdown of incremental spill prevention, control, and countermeasure (SPCC) compliance costs associated with the proposed imposed by the 2002 rule-making. These costs are disaggregated by the types of facilities and/or pieces of equipment at oil and natural gas exploration and production (E&P) facilities under the jurisdiction of the rule, and the major compliance costs actions/elements necessary to comply.

As described in the main body of this report, these cost estimates account for the:

- Types of "facilities" (equipment, processes, sites, etc.) that must comply
- Portion of the "facilities" that might be subject to new requirements
- Requirements that apply to each type of "facility"
- Compliance actions taken by operators to comply
- Estimated incremental costs associated with compliance

Compliance cost impacts are adjusted to account for the two scenarios considered:

- Prices consistent to conditions in 2002, where wellhead crude oil prices averaged $22.51 per barrel (nominal), and wellhead natural gas prices averaged $2.95 per Mcf
- Prices consistent to 2005 conditions, where wellhead crude oil prices averaged $50.26 per barrel (nominal), and wellhead natural gas prices averaged $7.51 per Mcf.

These compliance cost estimates are presented in Table A-1. The table reports the costs assuming all impacted facilities must comply, and then adjusts these costs for those facilities associated with wells that would become uneconomic as a result of the imposition of the increased costs of SPCC compliance. The final result is a "net" cost of compliance associated only with those facilities that bear the compliance costs but that do not become uneconomic.

TABLE A-1 BREAKDOWN OF INCREMENTAL COMPLIANCE COSTS FOR POTENTIAL NEW SPCC REQUIREMENTS BY TYPE OF E&P FACILITY/EQUIPMENT AND COMPLIANCE COST ELEMENT (Reference Case)				
	No. of Affected Units	**Compliance Cost Element**	**Total Compliance Cost**	**Percent of Total**
Oil and Condensate Tank Batteries				
Oil Tank Batteries at Oil Facilities	169,932	Upgrade Plan	$476,103,040	
Condensate Tank Batteries at Gas Facilities	380,742	Upgrade Plan	$1,066,731,589	
	550,674		**$1,542,834,628**	18.4%
Produced Water Tanks -- Oil Facilities				
	4,770	Build containment, upgrade plan	$20,989,993	
	19,078	Build containment, new plan	$154,562,886	
	3,180	Implement I&M, contingency plan, upgrade plan	$7,633,969	
	12,719	Implement I&M, contingency plan, new plan	$77,604,484	
	39,746		**$260,791,331**	3.1%
Produced Water Tanks -- Gas Facilities				
	1,022	Build containment, upgrade plan	$4,497,856	
	4,088	Build containment, new plan	$33,120,618	
	2,385	Implement I&M, contingency plan, upgrade plan	$5,725,476	
	9,539	Implement I&M, contingency plan, new plan	$58,203,363	
	17,034		**$101,547,313**	1.2%
Process Vessels -- Oil Facilities				
	19,117	Build containment, upgrade plan	$84,132,958	
	76,470	Build containment, new plan	$619,525,357	
	6,372	Implement I&M, contingency plan, upgrade plan	$15,299,394	
	25,490	Implement I&M, contingency plan, new plan	$155,528,752	
	127,449		**$874,486,462**	10.4%
Process Vessels -- Gas Facilities				
	14,278	Build containment, upgrade plan	$62,834,637	
	57,111	Build containment, new plan	$462,692,046	
	4,759	Implement I&M, contingency plan, upgrade plan	$11,426,341	
	19,037	Implement I&M, contingency plan, new plan	$116,156,531	
	95,185		**$653,109,555**	7.8%
Compressors -- Oil Facilities				
	44	Build containment, upgrade plan	$195,425	
	178	Build containment, new plan	$1,439,038	
	400	Implement I&M, contingency plan, upgrade plan	$959,514	
	1,599	Implement I&M, contingency plan, new plan	$9,754,108	
	2,220		**$12,348,084**	0.1%
Compressors -- Gas Facilities				
	404	Build containment, upgrade plan	$1,778,625	
	1,617	Build containment, new plan	$13,097,169	
	3,637	Implement I&M, contingency plan, upgrade plan	$8,732,857	
	14,550	Implement I&M, contingency plan, new plan	$88,775,431	
	20,208		**$112,384,082**	1.3%
Blowdown/Emergency Tanks -- Oil Facilities				
	2,271	Build containment, upgrade plan	$9,993,804	
	9,084	Build containment, new plan	$73,590,842	
	6,813	Implement I&M, contingency plan, upgrade plan	$16,356,163	
	27,251	Implement I&M, contingency plan, new plan	$166,271,526	
	45,418		**$266,212,336**	3.2%

TABLE A-1 (Continued)

BREAKDOWN OF INCREMENTAL COMPLIANCE COSTS FOR POTENTIAL NEW SPCC REQUIREMENTS BY TYPE OF E&P FACILITY/EQUIPMENT AND COMPLIANCE COST ELEMENT (Reference Case)

	No. of Affected Units	Compliance Cost Element	Total Compliance Cost	Percent of Total
Blowdown/Emergency Tanks -- Gas Facilities				
	6,047	Build containment, upgrade plan	$26,611,494	
	24,188	Build containment, new plan	$195,957,631	
	18,141	Implement I&M, contingency plan, upgrade plan	$43,553,178	
	72,563	Implement I&M, contingency plan, new plan	$442,747,678	
	120,938		**$708,869,980**	8.5%
Flow and Gathering Lines -- Oil Facilities				
	3,059	Build containment, upgrade plan	$22,637,619	
	12,235	Build containment, new plan	$184,769,953	
	27,529	Implement I&M, contingency plan, upgrade plan	$141,798,239	
	110,116	Implement I&M, contingency plan, new plan	$1,167,406,894	
	152,939		**$1,516,612,705**	18.1%
Flow and Gathering Lines -- Gas Facilities				
	2,284	Build containment, upgrade plan	$16,906,889	
	9,138	Build containment, new plan	$137,995,300	
	20,560	Implement I&M, contingency plan, upgrade plan	$105,901,908	
	82,240	Implement I&M, contingency plan, new plan	$871,876,958	
	114,222		**$1,132,681,055**	13.5%
Truck Loading Areas -- Oil Facilities				
	2,379	Build containment, upgrade plan	$15,227,985	
	9,516	Build containment, new plan	$96,128,910	
	21,411	Implement I&M, contingency plan, upgrade plan	$83,523,177	
	85,646	Implement I&M, contingency plan, new plan	$651,045,452	
	118,953		**$845,925,523**	10.1%
Truck Loading Areas -- Gas Facilities				
	10	Build containment, upgrade plan	$65,058	
	41	Build containment, new plan	$410,690	
	91	Implement I&M, contingency plan, upgrade plan	$356,835	
	366	Implement I&M, contingency plan, new plan	$2,781,454	
	508		**$3,614,038**	0.0%
Pump Jacks -- Oil Facilities Only				
	7,137	Build containment, upgrade plan	$31,409,638	
	28,549	Build containment, new plan	$231,289,467	
	3,059	Implement I&M, contingency plan, upgrade plan	$7,343,709	
	12,235	Implement I&M, contingency plan, new plan	$74,653,801	
	50,980		**$344,696,615**	4.1%
TOTAL COST OF SPCC COMPLIANCE (All Facilities)	**1,456,474**		**$8,376,113,710**	
LESS COST FOR UNECONOMIC WELLS*	**2002 Case**		**$5,218,160,784**	
	2005 Case		**$3,740,810,931**	
NET COST OF SPCC COMPLIANCE	**2002 Case**		**$3,157,952,926**	
(Subtracting Costs for Uneconomic Facilities)	**2005 Case**		**$4,635,302,779**	

* Facilities that become uneconomic as a result of increased SPCC costs are not assumed to bear costs of compliance, since wells would be shut in and associated facilities shut down

December 13, 2006

DOE Assessment of SPCC Requirements for U.S. Oil and Natural Gas Production -- Overview of Analytical Considerations and Methodology

Analysis focused on the potential implications of SPCC compliance on oil and gas production, with emphasis on production that is economically marginal and most impacted by increased costs. The basic steps in the analyses included the following:

- Determining what types of facilities/equipment must comply
    - Produced water treatment
    - Process vessels -- separators, heater treaters, compressors, pump jacks
    - Flow and gathering lines/ process and facility piping
    - Emergency and temporary containers and tanks
    - Truck loading areas
- Determining how many facilities/pieces of equipment are subject to new requirements
    - Estimates were made as to the total numbers of each type, along with the portion are already in compliance
- Determining the requirements for each type of facility/piece of equipment
    - Build new secondary containment
    - Where "impractical," implement I&M program and contingency plan
    - Some will be incorporated under an existing (upgraded) SPCC plan
    - Some will require a new SPCC plan
- Determining the incremental costs associated with compliance
    - Cost estimates based on those provided by industry and EPA sources
- Determining how much industry will spend to comply with the new requirements
    - Total costs of compliance were estimated by multiplying the number of facilities/pieces of equipment corresponding to each compliance option, multiplied by the unit cost of compliance for that option
    - Total incremental compliance costs associated with oil and gas production facilities, respectively, were divided by the number of producing oil and gas wells in the U.S, respectively, to determine average costs per oil and gas well

- Determining the impact of these requirements on U.S. oil and gas production
  - Step1. Established data base of U.S. oil and gas production by using EIA database of U.S. oil and gas wells sorted by state and production rate category. This provides a "representative" or "model" well for each state and production rate category
  - Step 2: Estimated average annual revenues per well for each representative well based on EIA data for average annual wellhead oil and gas prices
  - Step 3: Estimated production costs for each representative well using data from EIA's annual survey of O&M costs
  - Step 4: Estimated average annual income per representative well, by subtracting the average O&M costs per well from the average estimated revenue per well. This income represents that corresponding to well economics before the imposition of new SPCC requirements.
  - Step 5. Estimated average annual operation income per representative well, accounting for incremental SPCC requirements by adding the incremental SPCC compliance costs to the average O&M costs per well, and then subtracting the revised average O&M costs per well from the average estimated revenue per well. This income represents that corresponding to well economics after the imposition of the SPCC requirements.
  - Step 6. Determined shut-in production as a result of the increased costs due to SPCC requirements
  - Step 7. Extrapolated results to all U.S. production, since not all wells and production were represented in the EIA production well database
  - Step 8. Estimated other associated economic impacts based on the production impacts
    - Compliance expenditures, accounting for shut-in production
    - Lost royalties
    - Lost state and local severance/ad valorum taxes
    - Lost state income taxes
    - Lost federal income taxes